The Role of the Canadian Oil Sands in the US Market

Energy Security, Changing Supply Trends, and the Keystone XL Pipeline

SPECIAL REPORT™

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THE ROLE OF THE CANADIAN OIL SANDS IN THE US MARKET: ENERGY SECURITY, CHANGING SUPPLY TRENDS, AND THE KEYSTONE XL PIPELINE

EXECUTIVE SUMMARY

A key uncertainty about the future role of the Canadian oil sands is whether the US government will allow production from Canada to expand its reach into the United States. The US Department of State (DOS) is reviewing the application by TransCanada to build a pipeline from Alberta, Canada, to the US Gulf Coast. For the Keystone XL pipeline review, the DOS commissioned studies to evaluate US market dynamics and life-cycle greenhouse gas (GHG) emissions as part of the Supplemental Draft Environmental Impact Statement (SDEIS) released for comment in April 2011. This IHS CERA Special Report identifies and explains differences between the SDEIS and IHS CERA analyses on three critical questions:

- **When is the new pipeline infrastructure required, and could this pipeline affect gasoline prices?** By 2015 oil sands exports will likely exceed refining capacity in the US Midwest—currently the main market for oil sands output. Keystone XL will increase supply to the broader US market—namely the US Gulf Coast. For a given level of demand, higher supply would lower prices for crude oil, which is the most important factor shaping gasoline prices.

- **What are the likely substitutes for oil sands crudes if Keystone XL is not approved?** The US Gulf Coast is the world's most sophisticated refining region. In the absence of oil sands supply, Gulf Coast refiners are expected to demand similar volumes of heavy crude oils, but from more distant sources of supply.

- **What are the incremental GHG emissions associated with consuming oil sands?** The increase in GHG emissions from oil sands, and consequently from the proposed pipeline, is not as high as is often perceived. On a life-cycle basis, GHG intensity of the average oil sands import is about 6 percent higher than that of the average crude oil consumed in the United States.

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INTRODUCTION

High oil prices during a time of potentially momentous change in North Africa and the Middle East and rising demand from emerging markets are raising concerns about availability of oil and about future price trends. In the realm of US energy security, one of the biggest achievements of the past decade has been the growing use of Canadian oil sands production to supply the US market. Oil sands production has made Canada the number one supplier by far of foreign oil to the United States.

In 2010 the United States imported about 2 million barrels per day (mbd) of oil from Canada, or 22 percent of total imports. About 1.1 mbd of Canada's crude oil exports were from the oil sands of Alberta—a mega-resource right next door to the United States and connected by land-based pipelines. Oil sands matched the total US imports from Mexico, the number two foreign supplier, and in 2011 are poised to become the single largest source.

Canadian oil sands could play a steadily growing, long-term role in supplying the US market for many years to come. However, US pipeline infrastructure needs to catch up with changing supply trends and expanding supply—namely, rising output from Canada, as well as the rapidly growing output from the Bakken Formation in North Dakota and Montana. Currently Canadian and Bakken oil production is bottled up in the US Midwest, a regional market that is nearing saturation. Inadequate pipeline infrastructure could limit US access to rising Canadian and Bakken supply.[1]

The proposed 700,000 barrel per day (bd) Keystone XL pipeline would provide the first large-scale pipeline connection between Canada and the US Gulf Coast. Such an expansion would foster higher production and greater use of North American oil in the US market. Economic logic dictates that more supply results in lower prices for a given level of demand. A more dynamic and flexible pipeline system that boosts continental oil supply would be a big positive for American consumers and US energy security.

The US pipeline system was constructed in previous decades to deliver crude to the US Midwest from the US Gulf Coast, not the other way around. The current lack of significant pipeline capacity to expand the market "reach" of Canadian and Bakken crude oil deprives the broader US market of oil that is nearby and available.

The oil sands are part of a larger, dense network of US trade and investment relations with Canada, the largest market for American goods. In 2010 US-Canada trade totaled $525 billion. Eight million American jobs depend on trade with Canada.[2] More than 20,000 American

1. In this report the US Midwest is defined as Petroleum Administration for Defense District 2 (PADD 2). The region comprises Illinois, Indiana, Iowa, Kansas, Kentucky, Michigan, Minnesota, Missouri, Nebraska, North Dakota, Oklahoma, Ohio, South Dakota, Tennessee, and Wisconsin. The US Gulf Coast is defined as PADD 3 and comprises Alabama, Arkansas, Louisiana, Mississippi, New Mexico, and Texas.
2. Testimony by James Burkhard, Managing Director of IHS CERA, before the US House of Representatives Subcommittee on Energy and Power, in Washington, DC, on May 23, 2011.

About This Report

This Special Report, including the appendix, is a detailed supplement to testimony presented by James Burkhard, Managing Director, IHS CERA, on May 23, 2011, before the US House of Representatives Committee on Energy and Commerce Subcommittee on Energy and Power, in Washington, DC, and provides details on the analysis supporting the testimony.

jobs already depend on oil sands development, and this number could grow significantly if oil sands investment expands through initiatives such as the proposed $7 billion Keystone XL pipeline project, which is among the largest "shovel-ready" projects in the United States.[1] Failure to expand access to the US market for additional Canadian supply would risk damaging the overall US-Canada relationship and leave the United States more reliant on distant oil supplies.

THE KEYSTONE XL PIPELINE DECISION

A key uncertainty about the future role of the Canadian oil sands is whether the US government will allow production from Canada to expand its reach into the United States. The US Department of State (DOS) is reviewing the application by TransCanada to build a pipeline from Alberta, Canada, to the US Gulf Coast. Since this pipeline, known as Keystone XL, would cross an international border, the US DOS will determine whether a "Presidential Permit" will be issued to allow the pipeline to be built across the border and will also lead the project's environmental review (see the box "Proposed Keystone XL Pipeline"). Keystone XL would enable shipment of more oil sands production to the United States and could also transport additional US-produced oil to US Gulf Coast refiners.

For the Keystone XL pipeline review, the DOS commissioned studies to evaluate US market dynamics and life-cycle greenhouse gas (GHG) emissions as part of the Supplemental Draft Environmental Impact Statement (SDEIS) released for comment in April 2011. This IHS CERA Special Report identifies and explains differences between the SDEIS and IHS CERA analyses on three critical questions:

- **Question One:** When is the new pipeline infrastructure required, and could this pipeline affect gasoline prices?
- **Question Two:** What are the likely substitutes for oil sands crudes if Keystone XL is not approved?
- **Question Three:** What are the incremental GHG emissions associated with consuming oil sands?

The appendix provides details on the methodology, calculations, and assumptions supporting the analysis.

1. Ibid.

Proposed Keystone XL Pipeline

The proposed Keystone XL crude oil pipeline would be 1,711 miles long (2,754 kilometers [km]), and 36 inches in diameter. It would begin at Hardisty, Alberta, and extend southeast through Saskatchewan, Montana, South Dakota, Nebraska, Kansas, and Oklahoma to the Texas coast (see Figure 1). The US portion of the pipeline would be 1,384 miles (2,227 km) long. It would incorporate a portion of the existing Keystone Pipeline through Nebraska and Kansas to serve markets at Cushing, Oklahoma, before continuing through Oklahoma to a delivery point near existing terminals in Nederland, Texas. The pipeline would initially transport 700,000 bd of crude oil (primarily oil sands crude), with the option to expand to 830,000 bd. Keystone XL would enable greater flows of oil sands to the United States and create the first significant pipeline link from the US Midwest to the US Gulf Coast, which is the largest refinery region in the world. In addition to shipping oil sands, the project could transport US domestic crude oil production. As much as 150,000 bd could be transported from Cushing to the Gulf Coast via the proposed Cushing Marketlink project, and the proposed Bakken Marketlink could move 100,000 bd of oil supply.

QUESTION ONE: WHEN IS NEW PIPELINE INFRASTRUCTURE REQUIRED, AND COULD THIS PIPELINE AFFECT GASOLINE PRICES?

Today the United States is practically the only market for Canadian crude oil.[1] Although Canadian oil is exported to many US regions, the majority of exports, including oil sands, go to the US Midwest. With the two recent pipeline expansions from western Canada to the US Midwest commissioned in 2010 (Enbridge's Alberta Clipper at 450,000 bd and TransCanada's Keystone at 590,000 bd), new oil sands supply will be consumed in this region.

The increasing oil sands exports to the Midwest mean that refineries there will eventually (around 2015, in IHS CERA's outlook) no longer be able to process any additional oil sands crudes. This is because the capacity to refine oil sands in the US Midwest—a market facing flat to declining petroleum demand—will not keep pace with oil sands production growth. IHS CERA's view differs from the SDEIS (using a report by a third party). The SDEIS concludes that in the absence of the Keystone XL pipeline, oil sands production would not be affected until 2020. The conclusion is based on projections of when oil sands production will fill the current pipeline capacity. In contrast IHS CERA finds that refinery capacity—not pipeline size—is the crucial constraint.

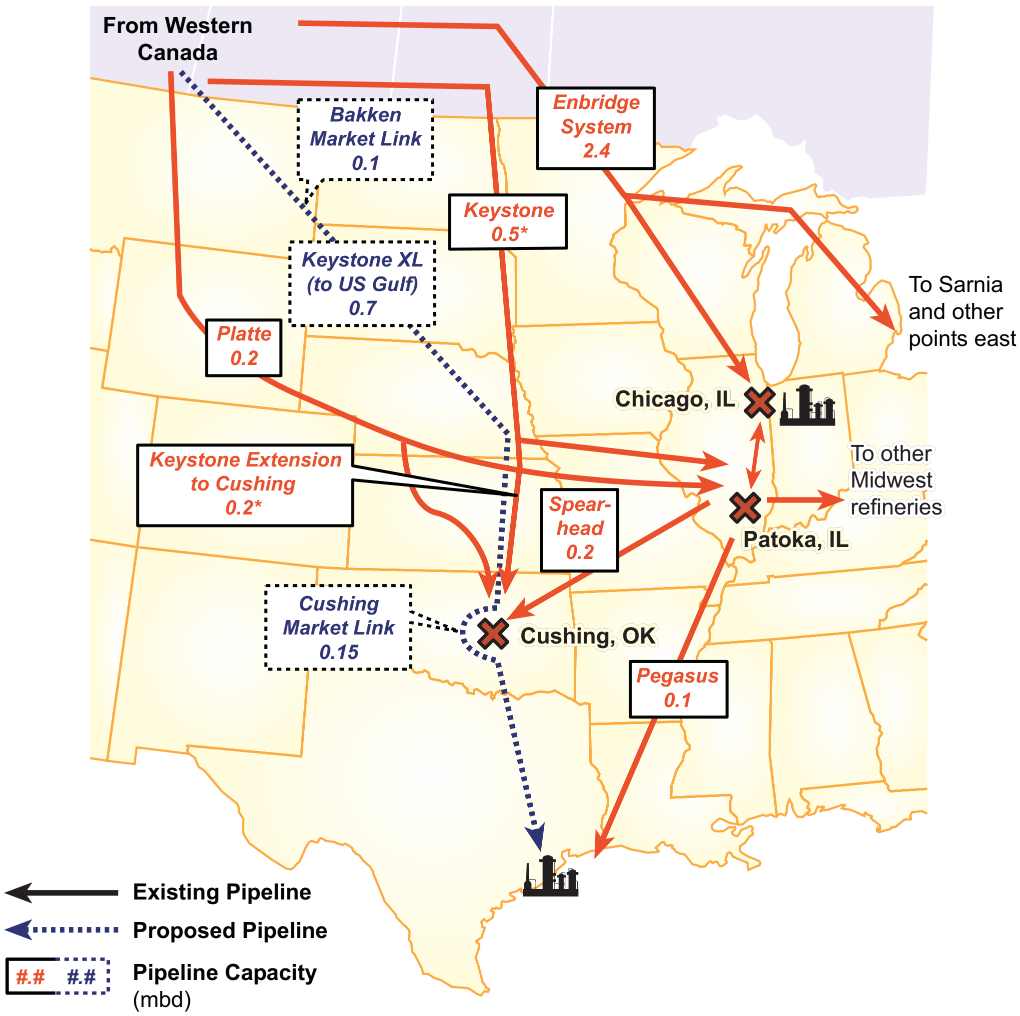
Crude Oil Supply in the US Midwest: Nearing Saturation

IHS CERA projects that the bulk of oil sands export growth to the US Midwest will be a product called dilbit, a heavy crude oil (see the box "Oil Sands and Conventional Crude Oil Definitions"). To prepare for increasing heavy crude supplies, a number of Midwest refiners are adding sophisticated upgrading units, called cokers, to their refineries, enabling them to accept growing dilbit volumes.[2] The combination of new pipeline capacity and additional refining capacity geared to accept dilbit means that in the near term the Midwest market

1. In 2010 only 2 percent of Canadian crude oil exports were to other countries (source: Canada NEB).
2. Four refiners (Conoco Phillips/Cenovus Wood River, Holly Tulsa, BP Whiting, and Marathon Detroit) have recently expanded or are planning to expand their capacities to accept heavy crude. In total they are adding about 170,000 bd of new coker upgrading units.

Figure 1

Current and Proposed Crude Flow from Western Canada to US Midwest and Gulf Coast



Source: IHS CERA, company information.
Note: Distances not drawn to scale. Pipeline capacities are rounded.
*Keystone Cushing extension will be taken over by the Keystone XL when XL is operational.
The Keystone pipeline will run at 0.3 mbd (down from the current 0.5 mbd) when this occurs.
10410-3

can absorb additional oil sands production. However, considering the potential for oil sands production to double in the next decade, by 2015 oil sands dilbit exports will likely exceed the Midwest refiners' ability to process the heavy crude. It's possible that some Midwest refiners could further upgrade their refineries, increasing the market for dilbit. But growing Canadian supplies to the US Midwest have coincided with a renaissance in light crude oil production in the region, led by the Bakken tight oil play, mainly in North Dakota but also extending into Montana. Total production from the formation has grown from less than 10,000 bd in 2003 to an estimated 400,000 bd in 2011, making North Dakota the fourth-

Oil Sands and Conventional Crude Oil Definitions

Conventional oil products. The terms light, medium, and heavy are often used to describe the density of crude oil. Typically, light crude oil has a density greater than 32 degrees API, and naturally yields greater volumes of valuable transportation products (such as gasoline and diesel). Heavy crudes have a density typically defined as 22 degrees API or lower. Heavy crudes naturally yield higher volumes of heavy products (such as road asphalt). To use these heavy products for transportation fuels, they must be converted or upgraded into more valuable light components. Refineries with sophisticated upgrading units, called cokers, are required to convert these heavy products into gasoline and diesel. Crudes in between light and heavy are termed medium. The United States produces heavy oil in California and imports heavy oil from a number of countries, including Canada, Mexico, and Venezuela.

Canadian oil sands products. Raw bitumen is denser than heavy oil; it's solid at ambient temperature and cannot be transported in pipelines or processed in conventional refineries. It must first be diluted with light oil liquid or converted into a synthetic light crude oil. The two most common products derived from oil sands are

- **Upgraded bitumen or synthetic crude oil (SCO).** This is produced from bitumen in refinery conversion units that turn very heavy hydrocarbons into lighter, more valuable fractions. SCO is typically a light sweet crude oil with no heavy fractions and an API gravity typically greater than 33 degrees.
- **Dilbit (bitumen blend, or diluted bitumen).** This is bitumen mixed with a diluent, typically a natural gas liquid such as condensate, to make the viscosity low enough for the dilbit to be shipped in a pipeline. Once mixed, dilbit is a heterogeneous crude oil mixture of about 22 degrees API, similar to the density and properties of other heavy crude supplies from California, Mexico, and Venezuela.

largest oil-producing state in the United States. IHS CERA estimates that production from the play could reach at least 800,000 bd by 2016–18. Production elsewhere in the Midwest is also rising: output in Oklahoma and Kansas has increased by about 10 percent since 2007. Consequently, with ample and growing light domestic crude supplies in the region, it is unclear whether refiners would make costly upgrades to process more heavy crude supply from Canada.

A sign of the need to expand pipeline capacity out of the Midwest, and of the oversupply of light crude in the region, is a lower price for West Texas Intermediate (WTI) crude oil relative to other major crude oils, including those traded on the US Gulf Coast and elsewhere in the world. WTI, priced at Cushing, Oklahoma, is the oil price that appears in the daily news. Historically WTI has been priced at a premium to other crude oils. The US Midwest was short of crude oil, and a higher price was needed to attract supply to refineries in the region and to reflect the high quality of WTI. Consequently, pipeline infrastructure was built to transport oil *to* the Midwest, but not *from* the Midwest. Cushing pipeline connections do not flow south to the US Gulf.

In a break from historical trends, there were times from 2006 to 2010 when WTI was priced several dollars below Light Louisiana Sweet (a crude oil produced in the US Gulf Coast) and Brent crude oil (a global price benchmark produced in the United Kingdom sector of the North Sea). But in recent months the WTI discount has ballooned to as much $18 per barrel as landlocked supply growth overwhelmed the Midwest crude oil market. WTI will remain vulnerable to significant discounts to other crude oils until more export capacity is developed to transport crude out of the Midwest to the US Gulf Coast.

The Keystone XL project could provide some relief for the oversupply of light crudes in the US Midwest. First, some Canadian light Synthetic Crude Oil (SCO) could bypass oversupplied light crude markets in the Midwest and go directly to the US Gulf Coast. Second, the project could transport some US domestic production from both Cushing and the Bakken to the US Gulf Coast.

What if increased oil sands access to the US market is derailed? Apart from the loss to consumers of a more dynamic pipeline network, Canadian oil sands producers would likely turn to Asia as a new export market, and US Gulf Coast refiners would continue to draw on current suppliers. However, some current suppliers such as Mexico and Venezuela are struggling to maintain production, and other suppliers are needed.

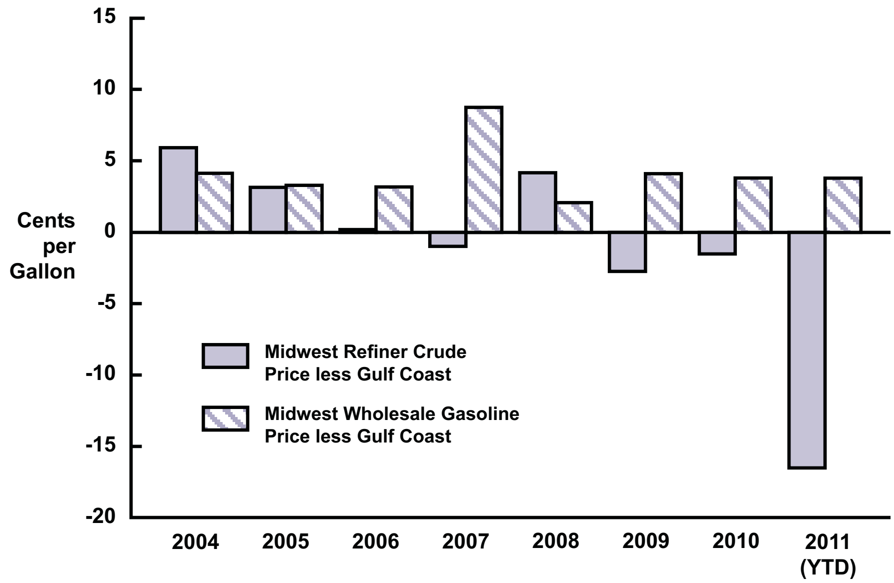
Does a Lower WTI Price Relative to Other Crude Prices Result in Lower Gasoline Prices for Consumers in the Midwest?

The answer is no. The price a consumer pays for a gallon of gasoline in the Midwest is comparable to the US average. There is no WTI discount for gasoline. Indeed, the first quarter average wholesale price for gasoline in the Midwest was $2.52 per gallon, about $0.04 above the US Gulf Coast average. Midwest prices are slightly higher because the Midwest must import gasoline from outside the region. In 2010 the net volume of Midwest gasoline imports from elsewhere in the United States amounted to about 500,000 bd. To attract this supply, Midwest buyers must buy gasoline at global market prices; otherwise, sellers would supply other markets. The Midwest gasoline market is and will remain dependent on supplies from outside the region to meet demand, which means that Midwest gasoline prices will continue to be shaped by global forces.

For gasoline sold in the US Midwest, the global market is the price of gasoline in the US Gulf Coast, which is one of three global refining centers that shape the global market price for gasoline (Rotterdam in the Netherlands and Singapore are the other two major “benchmark” markets for refined products). The single most important influence of the global market price of gasoline—which determines the price of gasoline the US Midwest—is the global market price of crude oil. For many years the price of WTI was a good indicator of the level of global crude and Midwest gasoline prices. But the disconnection of WTI from the global crude oil market—which has intensified in 2011—means that WTI does not reflect price levels for either the global crude oil or gasoline markets. Figure 2 compares Midwest crude and gasoline prices with the Gulf Coast. In 2004, 2005, and 2008 Midwest refiners paid a premium for crude oil (compared with Gulf Coast prices), yet the relative gasoline price between the two regions was not affected. In 2011 Midwest refiners have obtained crude at price levels well below the Gulf Coast, but relative gasoline prices—which are set by global forces—have not been affected.

Figure 2

Midwest Crude and Gasoline Prices Compared with the US Gulf Coast



Source: IHS CERA.
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Economic Logic: More Supply Lowers Price

Economic logic dictates that more supply lowers price at a given level of demand. The Keystone XL pipeline would increase oil supply available to the global oil market—and specifically to the US refining industry. It would not result in higher gasoline prices in the US Midwest.

The global market price for crude oil is the most important factor shaping the global market price for gasoline. Keystone XL would enable more supply to reach the global crude oil market—in this case, the US Gulf Coast. All else being equal, more supply of crude oil at a given level of demand would lower the global market price of gasoline—and thus lower the price of gasoline in the US Midwest. To be sure, many variables influence the price of oil: world oil demand growth, the pace of economic growth, the level of stability in major exporters, and the value of the dollar, to name just a few. But economic logic still holds: more supply lowers price at a given level of demand.

QUESTION TWO: WHAT ARE THE LIKELY SUBSTITUTES FOR OIL SANDS CRUDES IF KEYSTONE XL IS NOT APPROVED?

Keystone XL would deliver Canadian crude oil to the US Gulf Coast. The US Gulf Coast refining region consumes large volumes of heavy crude oils—crudes that are similar in quality to much of the future oil sands supply, namely dilbit. The volume of heavy crude imports to the region has been growing steadily from 1.3 mbd in 2000 to 1.9 mbd in 2010 (see Table 1).

Gulf Coast refineries are well suited to turn heavy crude oil into valuable transportation fuels. The Gulf Coast is already home to 30 percent of the world's coking capacity, and that number is still growing. This is a good indication that heavy oil imports will continue to increase (see Figure 3 and the box "Problems a Complex Refinery Faces When Processing Lighter Crudes").

Although total heavy oil imports have been growing, imports to US Gulf Coast refiners from Mexico declined from 1.1 mbd to 0.8 mbd between 2005 and 2010. The decline was offset by growing imports, mainly from Brazil, Colombia, Canada, and Venezuela. (Even though Gulf Coast Venezuelan heavy oil imports have risen, overall crude oil imports are down 30 percent over the same period.) Without new oil sands crude supply, the Gulf Coast refiners will continue to process heavy crude oils, given their large investments in coking capacity. For example, a new medium-size coking unit—a piece of equipment geared to process heavy crude oil—can cost $2 billion. Processing lighter crudes would idle large, expensive equipment. Therefore, when considering the incremental emissions resulting from substituting Canadian oil sands supply for other crudes, heavy crude oils should be assumed to be the primary substitute.

To be sure, not all oil supply transported by Keystone XL is expected to be heavy, because some of the growing supplies of lighter Bakken and SCO could also be shipped on the pipeline. Currently about 37 percent of US Gulf Coast imports are light crudes, and SCO and Bakken could be an alternative for some of this supply. However, considering the relatively low growth outlook for oil sands SCO supplies and limited capacity for on-ramping Bakken oil, these volumes are expected to be about 20 percent of the products shipped in the pipeline.

The IHS CERA conclusion differs from that of the SDEIS, which assumes that, in the absence of oilsands, the supply would be replaced with lighter Middle Eastern crude supplies. Considering the economic incentives for US Gulf Coast refiners to process higher-profit heavy crude supplies, combined with a longer-term outlook for growing heavy crude supplies, this assumption seems unlikely. In the absence of oil sands, Gulf Coast refiners are expected to demand similar volumes of heavy crude oils.

Table 1

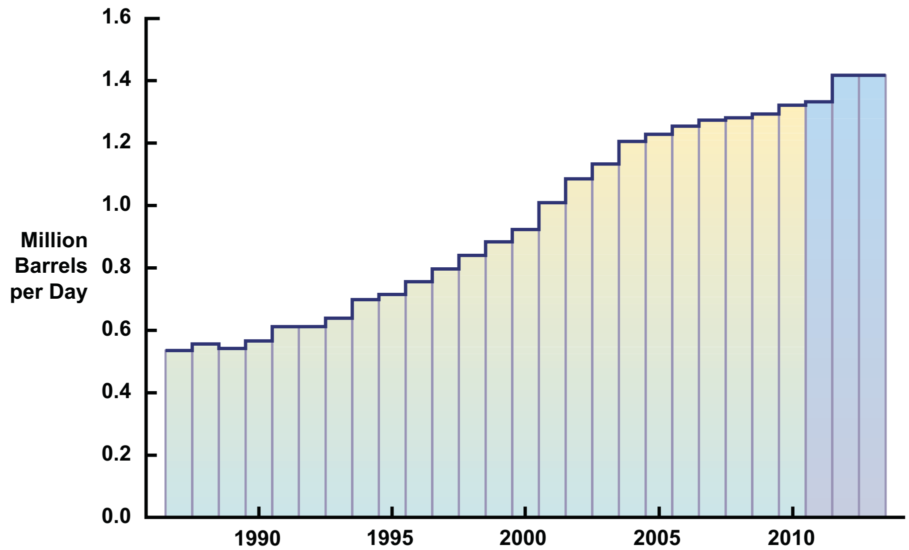
Heavy Crude Oil Imports to US Gulf Coast Refining Region

	2000	2005	2010
Heavy oil imports (22 API heavier) (mbd)	1.3	1.8	1.9
Total oil imports (mbd)	5.1	5.6	4.8
Percent of imports from heavy oil	25%	32%	39%

Source: US EIA, IHS CERA.

Figure 3

Current and Projected Total Coking Capacity in the US Gulf Coast



Source: IHS CERA, EIA.
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Problems a Complex Refinery Faces When Processing Lighter Crudes

A coking refinery configured for heavy crudes faces two problems when processing lighter crudes:

- Light crudes yield more light products, which overfill the units that upgrade transportation fuel quality (motor octane, sulfur removal, etc.).
- Light crudes yield less heavy products, so the refinery reactors used for upgrading are underused.

The result is a reduction in the volumes of gasoline and diesel produced. If a refiner configured to process heavy crude is forced to process 100 percent lighter crudes, the volume of gasoline and diesel produced can decrease by 15–20 percent, with a corresponding decrease in profits. This gives the refiner an incentive to purchase heavy crude oils.

QUESTION THREE: WHAT ARE THE INCREMENTAL GHG EMISSIONS ASSOCIATED WITH CONSUMING OIL SANDS?

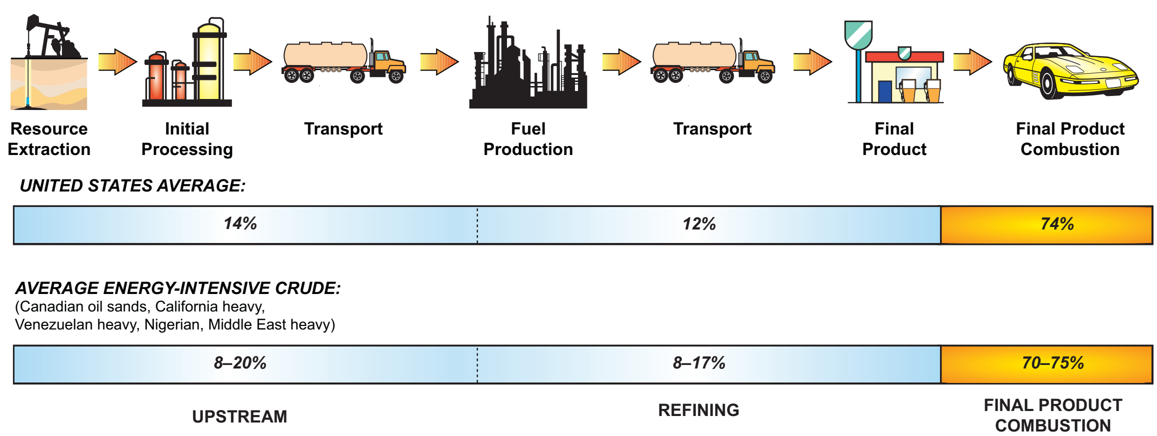
Comparing Oil Sands Emissions to Other Crude Oils

The life-cycle (also known as "well-to-wheels") emissions for a petroleum fuel cover all GHG emissions—from the production, processing, and transportation through to the final consumption of the fuel (see Figure 4).

In a previous report, IHS CERA found that oil sands (and the SCO derived from oil sands) are 5 to 15 percent more carbon intensive than the average crude oil consumed in the United States, other carbon-intensive crude oils (some domestic production from California and some imports from the Middle East, Nigeria, and Venezuela) are also produced, imported, or refined in the United States.[1] Moreover, the average life-cycle GHG emissions for the average Canadian oil sands product *actually imported into the United States* is about 6 percent higher than those of the average crude oil consumed in the United States. This 6 percent figure is based on the actual composition of oil sands exports to the United States instead of an overall range for oil sands produced in Canada.[2] There are two reasons for the 6 percent figure. First, much of the SCO imported is from mining operations, which tend to have GHG life-cycle emissions at the low end of the 5 to 15 percent range. Second,

Figure 4

Life-cycle GHG Emissions for Petroleum Fuels



Source: IHS CERA.
Note: Blue = well-to-retail tank. US average based on 2005 (US DOE NETL).
10207-2_2305

1. See the IHS CERA Special Report *Oil Sands, Greenhouse Gases, and US Oil Supply: Getting the Numbers Right;* visit http://www.ihs.com/products/cera/multi-client-studies/oil-sands-dialogue.aspx to download.
2. In 2009 oil sands products processed in the United States were 45 percent SCO and 55 percent bitumen blends. The majority of SCO imports come from mining operations with life-cycle GHG emissions that are 6 percent higher than those of the average crude consumed in the United States. The most common bitumen blend is dilbit. Dilbit has lower life-cycle emissions than bitumen because only 70 percent of the dilbit barrel is derived from the oil sands (the remainder consisting of less carbon-intensive liquids such as natural gas condensates).

another large segment of US oil sands imports is dilbit, a blend of bitumen and condensates. About 30 percent of dilbit consists of condensates, which are light liquids and less carbon intensive to produce.

Looking forward, the GHG intensity of US oil sands imports is expected to stay relatively constant at around 6 percent higher than the average US crude consumed, with the potential to decline slightly.[1]

Oil Sands GHG Intensity: Differences Between SDEIS and IHS CERA

The SDEIS, using data from a 2009 US Department of Energy National Energy Technology Laboratory (DOE NETL) study, reports that on a life-cycle basis gasoline consumed in the United States from oil sands results in 17 percent more GHG emissions than the average barrel consumed in the United States—higher than the IHS CERA value.[2]

There are two primary reasons for the difference. First and most important, DOE NETL assumes that the GHG intensity of oil sands extraction and upgrading is 1.5 times higher than IHS CERA's figure and outside the range of other studies. The NETL oil sands values do not represent the current GHG intensity of oil sands and therefore could be viewed as a mischaracterization. Also, the IHS CERA results (which compare oils sands to other crudes) are similar to the relative results of two other independent studies used within the SDEIS (Jacobs 2009 and TIAX 2009).[3] Second, the basis of comparison is different: IHS CERA considers the full barrel of products produced from each barrel of oil, whereas the DOE NETL study considers the emissions for only one product—gasoline. (See the appendix for a more detailed explanation of the differences between the IHS CERA results and other studies.)

The increase in GHG emissions from oil sands, and consequently from the proposed Keystone XL pipeline, is not as high as in the SDEIS or as perceived by some other observers. Indeed, life-cycle GHG emissions from the oil sands are comparable to those of many other crude oils consumed in the United States. The GHG intensity of likely crude oil substitutes is closer to that of oil sands than some believe.

1. The majority of oil sands growth is projected to be dilbit blend, whose emissions are on average about 6 percent higher than those of the average crude consumed in the United States on a life-cycle basis (the same as the current import average), and the majority of SCO will remain from mining operations whose emissions are also about 6 percent higher than average US crude on well-to-wheels basis. Going forward, ongoing improvements in energy efficiency combined with growing production of bitumen-only from mining operations will potentially lower industry-average emissions.

2. DOE NETL, *An Evaluation of the Extraction, Transport and Refining of Imported Crude Oils and the Impact on Life Cycle Greenhouse Gas Emissions,* March 27, 2009.

3. Jacobs and TIAX studies: *Life Cycle Assessment Comparison of North American and Imported Crudes,* Jacobs Consultancy, July 2009; and *Comparison of North American and Imported Crude Oil Life-cycle GHG Emissions,* TIAX LCC, July 2009. See the IHS CERA Special Report *Oil Sands, Greenhouse Gases, and US Oil Supply: Getting the Numbers Right*. These studies were used as inputs to the IHS CERA meta-analysis of GHG emissions from oil sands and other crude oils.

Drawing a Boundary Around the United States: Incremental GHG Emissions Associated with Consuming Oil Sands Crudes

If the Keystone XL pipeline were not constructed, heavy crude oils from other foreign producers would substitute for the majority of the lost Canadian oil sands supply. A smaller fraction of the oil sands supply, probably about 20 percent, is likely to be substituted by relatively lighter crude oils.

Assuming that 80 percent of the substitute crude is heavy, with a GHG intensity between Mexican Maya and Venezuelan heavy crudes, and 20 percent of the substitute crude oil is light, with a GHG intensity of a relatively lighter Middle East crude oil, IHS CERA estimates that on a life-cycle basis the construction of Keystone XL would result in between 7.5 and 11 million metric tons of carbon dioxide equivalent ($mtCO_2e$) per year more emissions associated with US oil supply than would be the case if no pipeline were constructed (see Table 2 and the appendix for more information on calculation).[1] Or put another way, the emissions are equivalent to between 1.5 and 2.1 million more vehicles on the road, or about 1.8 to 2.5 average-size coal-fired power plants.[2]

The IHS CERA result is well below the incremental GHG emissions assumed in the SDEIS base case, which ranged between 10 and 23 $mtCO_2e$ per year. There are two reasons for the discrepancy: first, SDEIS assumed that all oil sands supply is substituted for relatively light Middle East crude, which is unlikely. Second, the high side of the SDEIS GHG emissions range (23 $mtCO_2e$ per year) reflects the results of the DOE NETL study, which does not represent current operations and overestimates the GHG emissions for oil sands crudes.

Does Drawing a Boundary Around the United States Make Sense?

If new market access for oil sands crudes does not materialize in the United States, economic forces would eventually drive oil sands supplies to new markets. From a global perspective, if oil sands production is not materially affected (and the oil is simply consumed in another

Table 2

Life-cycle Incremental GHG Emissions of Displacing Keystone XL Oil Sands Crudes with Substitutes[1]

($mtCO_2e$ per year)

	700,000 bd Pipeline	830,000 bd Pipeline
Jacobs 2009	(7.9)	(9.4)
TIAX 2009	(9.4)	(11.1)
IHS CERA	(7.4)	(8.8)

Source: IHS CERA.
1. Assumes that substitute crude is 80 percent heavy oil and 20 percent light oil.

1. Lighter Middle East crude oil is defined as 31 degrees API—just at the cutoff between light and medium crude oil.
2. GHG equivalencies based on EPA calculator—http://www.epa.gov/cleanenergy/energy-resources/calculator.html#results.

country), then global GHG emissions are not affected. In fact, considering a scenario of oil sands crudes being transported to distant locations while other global crudes are transported from distant locations to the US Gulf Coast, it's likely that GHG emissions could be somewhat higher (because more energy would be consumed in transportation).

Even if the United States decides to restrict market access to oil sands crudes, it may not affect overall oil sands GHG emissions in the long term. But it would damage the US-Canada relationship and leave the United States more reliant on distant oil supplies.

CONCLUSION

The oil sands provide an example of the need to find the right balance among economic, security, and environmental concerns. An informed dialogue will help both Canadians and Americans to reach a consensus that will enhance mutual prosperity and security. Key fundamental facts are

- The oil sands are a "mega" resource next door to the United States.
- Greater oil sands production has made Canada the number one supplier by far of foreign crude oil to the United States.
- Growth in oil sands production is reorienting imports and enhancing energy security through a land-based pipeline system with a neighboring country, not waterborne imports.
- Expanding pipeline capacity from Canada to the US Gulf Coast via the proposed Keystone XL project would provide more flexibility to the US supply system, allow infrastructure to begin to catch up with oil supply trends (namely the growing flow of Canadian oil), and enable increased US domestic production in the upper Midwest.
- A larger, more dynamic pipeline system benefits consumers, compared with a more constricted system that is less able to handle shifts in demand and supply.
- The Keystone XL project would increase oil supply available to the global market—and specifically to US Gulf Coast refineries. Economic logic dictates that more supply lowers prices for a given level of demand.
- The oil sands are part of a larger, dense network of trade and investment relations between the United States and Canada. Eight million American jobs depend on trade with Canada. Failure to enable oil sands to gain broader access to the US market could damage a bilateral relationship that has proved to be mutually beneficial for many years.
- Life-cycle GHG emissions of oil sands are 5 to 15 percent higher than those of the average crude oil consumed in the United States. The composition of oil sands products actually imported into the United States means that life-cycle GHG emissions of US oil sands imports are only 6 percent higher than for the average crude.

The United States and Canada have a deep and mutually beneficial relationship rooted in strong economic, political, and cultural connections. Energy, and oil in particular, is a key element of the overall relationship. Canada's oil sands have become an integral part of the fabric of US energy security—with the potential to play an increasingly important role for many years to come.

APPENDIX

This appendix includes details on the methodology, calculations, and assumptions supporting our analysis in three parts:

- requirement for new pipeline capacity
- oil sands GHG intensity comparison with other studies
- calculating incremental GHG emissions from oil sands in Keystone XL compared with substitutes

REQUIREMENT FOR NEW PIPELINE CAPACITY

As a result of the completion of two new pipelines that deliver Canadian oil to the US Midwest, Alberta Clipper and Keystone (totaling 1 mbd of pipeline capacity), we assume that growth in oil sands production over the next several years will flow to the Midwest. Using the Canadian Association of Petroleum Producers (CAPP) 2010 oil supply forecast from western Canada and assuming that Canadian demand for western Canadian crude supply remains flat, it would be between 2018 and 2020 before oil sands supply fills the existing surplus pipeline capacity (see Table A1).

However, pipeline capacity is not projected to be the bottleneck that curtails oil sands supply growth. Because of the increasing volumes of dilbit, which requires sophisticated refineries to upgrade the heavy crude, limited coking capacity will curtail growth first. Based on the current expansions (either under way or planned), we estimate that 600,000 to 750,000 bd of dilbit growth can be absorbed by the Midwest market, and this limit could be hit by 2015 (see Table A1). With ample light crude supply growth in the domestic market, Midwest refiners will have less incentive to spend billions of dollars in upgrades to take heavy crudes. The bottleneck will reduce the price of oil sands products and constrain growth. Also, oil demand in the US Midwest is generally flat to declining in the long term—as is overall US oil demand—so there is not likely to be a need for significant growth in refining capacity to serve the US Midwest market.

Another important consideration is that the Keystone XL project will redirect some of the existing Keystone pipeline capacity to the US Gulf Coast. This will reduce available pipeline capacity to the Midwest by about 200,000 bd. In this case, by 2015 excess capacity to the Midwest would be minimal. (Between the new Alberta Clipper and the Keystone pipelines to the Midwest, capacity would be reduced to about 840,000 bd, and this would be filled by 2016 with the current growth forecast; see Table A1).

OIL SANDS GHG INTENSITY COMPARISON WITH OTHER STUDIES

Differences in Oil Sands GHG Intensity: SDEIS and IHS CERA

The SDEIS (using data from the DOE NETL-2009) reports that on a life-cycle basis consumption of gasoline from oil sands results in 17 percent more GHG emissions than that from the average barrel of crude oil consumed in the United States. In our study, and

Table A1

Growth in Western Canadian Supply Compared with Pipeline Capacity

(thousands of barrels per day)

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Western Canada supply growth (mbd) (source: CAPP 2010)											
Oil sands: SCO	745	836	883	882	878	896	900	947	994	996	1,014
Oil sands: dibit	986	1,118	1,251	1,444	1,564	1,669	1,820	1,848	1,941	2,112	2,202
Conventional	834	802	777	756	735	710	685	664	640	617	595
Total western Canada supply	2,565	2,755	2,911	3,082	3,177	3,275	3,405	3,459	3,575	3,725	3,811
Less consumption in western Canada[1]	450	450	450	450	450	450	450	450	450	450	450
Supply for pipelines leaving western Canada	2,115	2,305	2,461	2,632	2,727	2,825	2,955	3,009	3,125	3,275	3,361
Existing major pipelines leaving western Canada											
Export lines in operation prior to 2010[2]	2,448	2,448	2,448	2,448	2,448	2,448	2,448	2,448	2,448	2,448	2,448
New pipelines to US Midwest in 2010 (Alberta Clipper and Keystone)	1,040	1,040	1,040	1,040	1,040	1,040	1,040	1,040	1,040	1,040	1,040
Total pipeline capacity leaving western Canada	3,488	3,488	3,488	3,488	3,488	3,488	3,488	3,488	3,488	3,488	3,488
Implied spare capacity in pipelines leaving western Canada	1,373	1,183	1,027	856	761	663	533	479	363	213	**127**[3]
Potential new oil supply flowing on Alberta Clipper and Keystone (2010 baseline)		190	345	517	611	710	**839**[4]	894	**1,009**[5]	1,160	1,245
Growth in dilbit to Midwest market (2010 baseline)		132	266	459	579	**683**[6]	835	863	956	1,127	1,216

Source: CAPP 2010, IHS CERA.

1. Assumes refineries run below total refining capacity and demand is static. In 2010 average crude runs for western Canada were 400,000 bpd (Source: NEB crude run reports).
2. Includes Enbridge System (1,868 mbd), Express (280 mbd), Trans Mountain (300 mbd).
3. If Keystone XL is not constructed; potential for all pipelines leaving western Canada to hit capacity.
4. If Keystone XL is constructed; potential for Alberta Clipper and Keystone lines to Midwest to hit capacity.
5. If Keystone XL is not constructed; potential for new Keystone and Alberta Clipper lines to hit capacity.
6. Potential for Midwest refiners to be oversupplied with dilbit.

comparing a more relevant full barrel of refined products, the average oil sands product exported to the United States results in life-cycle emissions that are 6 percent higher than for the average US barrel consumed.

There are two primary reasons for the difference. First and most important, DOE NETL assumes that the GHG intensity of oil sands extraction and upgrading are 1.5 times higher than IHS CERA and other study results. This is a mischaracterization of the GHG intensity of oil sands production. Second, the basis of comparison is different: IHS CERA considers the full barrel of products produced from each barrel of oil, whereas the DOE NETL study considers the emissions for only one product—gasoline.

First, DOE NETL GHG emissions are about 1.5 times higher than the IHS CERA and others results.

- **Oil sands mining and upgrading emissions.** Slightly more than half of today's oil sands production is from mining and upgrading. DOE NETL 2009 assumes a 2005 mining and upgrading emission value of 134 kilograms of CO_2 ($kgCO_2$) per barrel of SCO. The source for this value is not clear. The DOE NETL values are higher than those of any studies used in the IHS CERA analysis (which looked at the range of results across ten studies for mining and upgrading) as well as other operator reports (see Table A2). Using a 2005 GHG emissions value can result in mischaracterization of current operations; emissions in oil sands are not static, and on average the oil sands industry continues to improve its overall efficiency. For instance in 2005 the Syncrude project had emissions of 100 $kgCO_2$ per barrel. In 2009 emissions were reduced to 95 $kgCO_2$ per barrel of SCO.
- **Thermal extraction emissions.** Thermal methods inject steam into the wellbore to heat up the bitumen and allow it to flow to the surface. Two thermal processes are in wide use in the oil sands today: steam-assisted gravity drainage (SAGD) and cyclic steam stimulation (CSS). On average SAGD has lower GHG emissions per barrel produced

Table A2

Comparing Estimates for GHG Emissions for Mining and Upgrading SCO

($kgCO_2e$ per barrel SCO)

	DOE NETL 2009	IHS CERA (average value)[1]	Syncrude (2009 Sustainability report)[2]	Suncor (2009, company data)[2]	Athabasca Oil Sands Project (Shell 2009 Oil Sands Report)[2]
Oil sands: mining and upgrading SCO	134	80 (results range from 34 to 122)	95	89	76

Source: DOE NETL 2009, IHS CERA.
1. Average value across 10 studies for SCO from mining, TIAX-AERI (July 2009), McCann 2007, GREET, GHGenius, RAND 2008,Jacobs-AERI 2009, Syncrude 2009/10, Shell 2006, NEB (2008), CAPP 2008.
2. Sources, Syncrude Sustainability reports, Suncor Energy Sustainability reports + company information, Shell Oil Sands Performance report, Muskeg River Mine and Scotford upgrader Sustainability report 2009.

than CSS. In 2009 over half of oil sands production was from the SAGD method, and SAGD volumes are growing.

For producing dilbit with thermal extraction, the DOE NETL study assumes that emissions are 1.5 times higher than the IHS CERA results (see Table A3). The DOE NETL study draws on a 2005 value for producing bitumen using the relatively high-emission CSS method (a process that represents less than half of current production). In the case of thermal production, there is no source for the estimate used in the DOE NETL 2009 paper; however, in a previous paper published in 2008 DOE NETL does provide a source for this value.[1] In addition, the estimate assumes the production of a barrel of bitumen-only, a product that cannot be transported via pipeline. IHS CERA assumes that dilbit, not bitumen, will be shipped down the pipeline and ultimately converted into refined products on the US Gulf Coast.

Second, the basis of comparison is different.

- **Gasoline basis compared with barrel of refined products.** Why did IHS CERA report the emissions per barrel of refined products rather than emissions per barrel of a specific product? In short, because each barrel of crude oil is converted into many products. When comparing the GHG emissions from different sources of crude, it is relevant to analyze the emissions resulting from all of the products produced, not just one. Additionally, allocating emissions across various refined products is a key challenge in life-cycle analysis. Including emissions from all products removes this potential source of error and confusion.

Table A3

Comparing Estimates for Producing Dilbit and Bitumen-only

($kgCO_2e$ per barrel)

	DOE NETL 2009	IHS CERA (average value) CSS[1]	IHS CERA (average value) SAGD[2]	IHS CERA Dilbit Average (50 percent SAGD, 50 percent CSS)
Oil sands: bitumen-only	81	83	69 (results range from 56 to 80)	—
Oil sands: dilbit[3]	—	60	50	55

Source: DOE NETL 2009, IHS CERA.
1. From TIAX-AERI (July 2009) (assumes SOR of 3.35).
2. Average value from six studies, equivalent to a SOR of 3.0. TIAX-AERI (July 2009), McCann 2007, GREET, GHGenius, RAND 2008,Jacobs-AERI 2009 (equivalent to SOR of 3).
3. Assumes that 70 percent of the barrel is from bitumen and 30 percent is natural gas condensate that emits 8 $kgCO_2e$ per barrel produced.

1. DOE NETL "Development of Baseline Data and Analysis of Life Cycle Greenhouse Gas Emissions of Petroleum-Based Fuels," November 2008. For bitumen production, a 2006 estimate for CCS Imperial was used.

CALCULATING INCREMENTAL GHG EMISSIONS FROM OIL SANDS IN KEYSTONE XL COMPARED WITH SUBSTITUTES

Comparing Keystone XL IHS CERA Results with Two Other Studies: Jacobs 2009 and TIAX 2009

For the IHS CERA calculation of the average GHG emissions associated with the Keystone XL pipeline presented in this report, we did not include the results of the DOE NETL study, as it overestimates oil sands emissions. We included the results of Jacobs 2009 and TIAX 2009, as well as the results of our own meta-analysis, which compares the GHG emissions of oil sands to those of other crude oils.

Because all three studies use different assumptions in modeling GHG emissions (for instance, different system boundaries, refinery complexity assumptions, and allocation of emissions among refinery coproducts), it is not valid to compare the absolute GHG emission estimates across the studies—it is like "comparing apples to oranges." The IHS CERA meta-analysis overcame this limitation by creating a common framework to compare the life-cycle emissions of oil sands across 12 studies.[1] The results of each study were converted into common units and common system boundaries. The assumptions across studies were made consistent to create a uniform set of assumptions for crude transport, refining, and distribution. Using this methodology, crudes from multiple studies can be compared on an "apples to apples" basis. To download full meta-analysis, including the GHG emission of full suite of crudes, the US average baseline, and oil sands crudes, please visit www2.cera.com\oilsandsdialogue.

Since the methodologies of the three studies (IHS CERA, Jacobs, TIAX) are inconsistent, the only way to compare the results as presented in the original studies is to consider the relative results between the same crude oils within each study. Table A4 presents the incremental emissions between lighter Middle East Crude East (Saudi Medium), Mexican Maya, and Venezuelan crudes and the average oil sands crude. When compared on a relative basis, the results of IHS CERA are within the range of the other studies of the relative GHG emissions of oil sands compared with the other crudes. In all cases, the studies had other crudes modeled; however, for the purpose of this calculation of incremental emissions, these three potential substitute crudes were considered.

Calculating Incremental GHG Emissions for Keystone XL

The difference between the average GHG emissions of oil sands crude and of the other three crudes on a per-barrel basis (last column of Table A4) was an input to the calculation of total GHG emissions from the Keystone XL pipeline. We assumed that 80 percent of the barrel is heavy crude (midway GHG emissions between Venezuelan crude and Mexican Maya) and the remaining 20 percent is lighter Saudi Medium crude. Taking the average incremental emissions on a per-barrel basis (between oil sands and this blend of crudes), we calculated the annual emissions for shipping 700,000 and 830,000 bd of oil sands in the Keystone XL pipeline for 365 days a year. The results of this calculation are the annual emission estimates for the Keystone XL, as shown in Table 2 of the main report.

1. See the IHS CERA Special Report *Oil Sands, Greenhouse Gases, and US Oil Supply: Getting the Numbers Right*.

Table A4

Comparison of Life-cycle Incremental GHG Emissions Between "Average Canadian Oil Sands" and Other Crudes

	Original Study Data: Gasoline (gCO_2e per MJ [LHV])[1]	Original Study Data: Diesel (gCO_2e per MJ [LHV])	IHS CERA Calculated[2]	Percent difference from "Average Canadian Oil Sands" (percent)	Incremental Emissions from "Average Canadian Oil Sands" ($kgCO_2e$ per barrel)
Jacobs 2009					
Average oil sands (SDEIS-ICF)[3]	108	105	600		
Saudi Medium	98.5	98	553	(8)	(47)
Mexico Maya	102	103	576	(4)	(24)
Venezuela Bachaquero	102	100	569	(5)	(30)
TIAX 2009					
Average oil sands (SDEIS-ICF)[3]	104	95	548		
Saudi Medium	91	83	473	(14)	(75)
Mexico Maya	93	86	487	(11)	(61)
Venezuela Bachaquero	102	91	532	(3)	(16)
IHS CERA 2009					
Average oil sands imported to United States (2006)[3]			518		
Saudi Medium			464	(10)	(53)
Mexico Maya			484	(7)	(34)
Venezuela Bachaquero			506	(2)	(12)

Source: IHS CERA, Jacobs 2009, TIAX 2009.

1. gCO_2 = grams of carbon dioxide.

2. To calculate the GHG emissions per barrel of crude for TIAX and Jacobs (which were originally on a product basis, such as gasoline and diesel), the average emissions were calculated assuming the following yields: Jacobs (59 percent gasoline, 35 percent diesel, and 6 percent others), TIAX (52 percent gasoline, 30 percent diesel, and 18 percent others). The emissions for a full barrel of crude oil were used when converted to full barrel of crude basis assuming 5.8 MMBtu per barrel of crude; this factor includes emissions from the full barrel including heavy products such as coke or asphalt, therefore 58 $kgCO_2e$ per barrel of crude was subtracted to estimate a per barrel of refined product basis. The IHS CERA results were already on a refined product barrel basis.

3. Jacobs 2009, TIAX 2009 the average Canadian oil sands export was assumed to be 50 percent dilbit, 44 percent SCO from mining, and 6 percent SCO from SAGD production using the same assumptions as the SDEIS-ICF study. For IHS CERA it was assumed to be 55 percent dilbit and 45 percent SCO from mining.